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Renewable Energy Finance and Project Ownership: The Impact of Alternative Development Structures on the Cost of Windpower

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ABSTRACT

This paper uses traditional financial cash-flow techniques to examine the impact of different ownership and financing structures on the cost of renewable energy, specifically windpower. Most large, non-hydroelectric, renewable energy projects are developed, owned, and financed by private non-utility generators. Recently, however, U.S. utilities have begun to consider owning and financing their own windpower facilities rather than purchasing power from independent renewable energy suppliers. Utilities in other countries have also expressed interest in direct renewable energy investments. A primary justification for utility ownership of wind turbine power-plants is that utility self-financing and ownership is cheaper than purchasing wind energy from non-utility renewable energy suppliers. The results presented in this paper support that justification, although some of the estimated cost savings associated with utility ownership are a result of suboptimal utility analysis procedures and implicit risk shifting. Financing terms and variables are shown to significantly impact windpower costs.

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INTRODUCTION

Renewable energy benefits society by reducing pollution (Proops et al., 1996), mitigating electricity price risks (Hoff and Herig, 1996), and increasing power supply flexibility (Chapman and Ward, 1996). Despite these, and other, benefits, cost-related and institutional impediments have prevented the large-scale development of non-hydroelectric renewable energy (Jackson, 1992). This paper demonstrates the importance of financing in the renewable energy project development process by exploring the effects of financing and ownership structure on the cost of renewable energy facilities. Specifically, the comparative cost impacts of non-utility generator (NUG), investor-owned utility (IOU), and public utility ownership and financing of windpower projects are assessed. The financial inputs that have the greatest impact on project costs are identified, and the tradeoffs associated with different types of project ownership are explored. Finally, the implications of electric industry restructuring on renewable energy finance and the alternative ownership results are discussed. Although the analysis techniques presented here are generally transferable to other renewable energy supply options and countries (with substantial caveats for tax effects, renewables incentives, etc.), this paper focuses on U.S. windpower development.

Because of the high capital costs and perceived resource and technology risks associated with most renewables, financing terms and variables can substantially influence project costs (Jackson, 1992; Mitchell, 1995). As the renewable energy market matures, policy-makers need to understand the financial processes and tradeoffs associated with different project ownership and financing structures. An

understanding of these issues helps explain why utilities have recently become interested in investing directly in renewable energy facilities rather than purchasing renewable power from private developers through power purchase agreements (PPAs). It also provides lessons for those interested in developing financial and market-creation mechanisms to promote renewable energy deployment.

Until recently, almost all large-scale, non-hydroelectric, renewable energy projects were developed, owned, and financed by private non-utility generators, which then sold electric output to nearby utilities through long-term PPAs. In the 1980s and 1990s, project financing has been the dominant renewable energy finance structure. In this arrangement, individual projects are financed on a stand-alone basis, and the lender looks primarily to the cash flow and assets of a specific project for repayment. Private NUG ownership and project financing is still the most common type of development structure, but alternatives are becoming more common. For example, a number of U.S. utilities have recently expressed interest in owning and financing their own facilities rather than purchasing windpower from independent NUGs. Although electric utilities, influenced by regulatory structures and institutional inertia, have historically been reluctant to invest in new and innovative energy technologies (National Regulatory Research Institute, 1994; Jackson, 1992), renewable energy cost reductions, technology advances, and mounting environmental pressure have encouraged some U.S. public and investorowned utilities to take an interest in windpower projects. In utility-ownership arrangements, a wind turbine equipment vendor/developer typically designs and constructs a project under a turn-key contract for the utility owner. Several utilityowned and financed renewable energy projects are currently in the development

stage in the U.S.ⁱ Electric utilities overseas are also becoming interested in investing in non-hydroelectric renewable energy facilities. In the U.K., for example, the third tranche of the Non-Fossil Fuel Obligation attracted bids from three U.K. utilities to supply windpower.

There are a number of reasons for direct utility involvement in renewable energy projects. One of the most important claims is that, due to financing and tax advantages, utility ownership and financing is less expensive than contracting with private NUGs to supply renewable energy. This paper explores that claim by estimating the cost of energy from U.S. windpower projects under different types of ownership and financing arrangements. Specifically, the nominal 20-year levelized cost of a 50 megawatt (MW) windpower facility under three ownership and financing arrangements is estimated: (1) private ownership with project financing; (2) investor-owned utility ownership with corporate financing; and, (3) public utility ownership with tax-exempt bond financing. To model the cost and financing variables, three cash-flow models were developed, one for each of the ownership and financing arrangements. All three models closely replicate the traditional type of analysis performed by the potential owners when considering the direct costs of owning power facilities. Awerbuch et al. (1996) and Felder (1996) conclude that a number of these traditional project-analysis techniques do not result in optimal power supply decisions, especially as they incorporate financial risk. Although the deficiencies of these techniques are discussed briefly in this study, the intent of this paper is to address current utility interest in owning and financing renewable energy projects. Therefore, the analyses presented in this paper uses the cost-assessment techniques most frequently applied by utilities and private developers. The term

"apparent" levelized cost is used to identify the cost calculated using traditional analysis techniques.

The remainder of this paper is organized in the following fashion. The first section briefly introduces the financial cash-flow models. Windpower input cost, tax, and operating assumptions are listed in the next section. Descriptions of the three ownership and financing arrangements considered in this paper are then provided, and estimates of the financing and tax differences among these structures are listed. The base-case results of the cost-assessment analysis are presented, and a number of scenarios are evaluated to determine the robustness of these results and the sensitivity of project costs to individual financial inputs. Finally, several issues related to the windpower ownership and finance results are analyzed, including: (1) the increased incidence and allocation of utility and ratepayer risk in utility-ownership scenarios; (2) the extent to which the calculated cost savings of utility ownership are a result of real cost reductions rather than suboptimal utility analysis procedures; and, (3) the effects of industry restructuring on renewable energy financing and the ownership and finance scenarios.

CASH-FLOW MODEL DESCRIPTIONS

To model windplant cost, tax, operating, and finance variables, three cash-flow models were developed.ⁱⁱ In all cases, the spreadsheet models assess a fictional 50 MW U.S. windpower project with a 20-year investment life.ⁱⁱⁱ Costs are evaluated and compared on a nominal levelized cost basis in 1997 dollars. Although the levelized cost output of these cash-flow models is frequently the most important

factor in project decisions, it is important to note that it is not the only criterion in project evaluation. Production cost and corporate financial modeling, as well as a variety of qualitative criteria, are also commonly used in decision-making processes.

The cost of the private windpower ownership, project finance scenario was determined using a 20-year pro-forma cash-flow model, which tracks yearly revenues, expenses, debt payments, and taxes, and estimates an after-tax, net equity cash flow. This type of financial model is typical of non-utility ownership, and is used in both: (1) bid price computation; and, (2) financial due diligence (Wong, 1995). The model estimates the nominal levelized power purchase price that would be required to meet the private owner's cost and financial constraints. This power purchase price is equivalent to the power purchase costs from the utility or ratepayer perspective.

Electric utilities typically use a screening analysis to determine the direct costs of individual power projects and to select promising ones. For IOU ownership with corporate financing, a traditional 20-year revenue-requirement cash-flow model is used. The revenue-requirement model used in this paper was adapted from one developed by PacifiCorp (Sims, 1995). For a more thorough description of the revenue-requirement approach, see Electric Power Research Institute (1993).

The scenario of public utility ownership with tax-exempt bond financing is assessed using a traditional 20-year cash-flow approach adapted from a model developed by California's Sacramento Municipal Utility District (SMUD) (Hart, 1995).

WINDPOWER PROJECT, COST, TAX, AND OPERATING ASSUMPTIONS

Table 1 lists the project size, operating, tax, and cost inputs used in the cash-flow analysis. The windpower project size, input costs, and operating assumptions are used consistently in all three of the cash-flow models. Although the final results are relatively insensitive to moderate changes in these variables, an attempt was made to provide reasonable estimates for U.S. windplant input costs (capital and operating) and operating performance. As discussed later, the treatment of taxes differ among the ownership arrangements. All values listed in the table are consistent with other sources, including Conover (1994), Electric Power Research Institute (1993), Hoffman (1995), Ing (1993), Karas (1994), OEM Development Corporation (1995), Utility Wind Interest Group (1991), and Wong (1995).

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The analysis presented in this paper assumes that capital costs, O&M, land expenses, insurance, and administration and management fees are the same for the three ownership scenarios. It is important to note that this assumption may not be entirely correct. To the extent that risk is transferred among the parties differently in the three ownership arrangements, these risks would be priced accordingly (Hoffman, 1995). For example, if a wind developer provides a utility owner with a fixed-price O&M contract, the developer risks associated with such a contract will likely result in higher overall O&M costs. Furthermore, the up-front turbine costs

associated with utility ownership may be higher than in private ownership because of manufacturer and developer mark-ups. Finally, a utility owner may require and be charged for a performance guarantee from the developer/turbine supplier. Therefore, the cash-flow analysis results presented in this paper most likely provide an upper bound to the cost savings actually available from utility ownership of windpower facilities in the U.S. Because the federal 1.5ϕ /kWh production tax credit (PTC) and renewable energy production incentive (REPI) are essential components of the cashflow analysis, a brief description of these incentives is included here. The National Energy Policy Act (EPAct) of 1992 contains provisions that encourage U.S. investment in renewable energy technologies. Specifically, a 1.5¢/kWh (\$1992) federal production tax credit is available to private and IOU owners of windpower facilities during the first ten years of operation. The PTC is adjusted for inflation. Unfortunately, not all equity investors have sufficient tax loads to absorb the full tax benefits of the tax credit, especially with alternative minimum tax (AMT) requirements. Hill and Hadley (1995) demonstrate that the AMT can reduce equity returns dramatically. This paper assumes that the PTC is fully absorbed by equity investors in the private and IOU ownership scenarios. The 1.5¢/kWh (\$1992) renewable energy production incentive is the non-profit analogue to the PTC. Because tax credits cannot be used by tax-exempt entities (i.e., public utilities), a similarly sized direct cash payment (REPI) is provided to non-profit windplant owners. Unlike the PTC, however, the REPI payments are subject to yearly congressional budget allocation and are therefore highly uncertain.

DIFFERENCES AMONG WINDPOWER OWNERSHIP AND FINANCE ARRANGEMENTS

Description of Ownership and Finance Arrangements

Private power producers have generally financed projects on a stand-alone, project finance, basis. In these arrangements, lenders look primarily to the cash flow and assets of a specific project for repayment rather than to the assets or credit of the promoter of the facility. The strength of the underlying contractual relationships among different parties is essential in project finance. Credit support for project finance comes in large part from the revenues associated with the power purchase agreement, so long-term fixed-price contracts are typically required.

In project finance, the lender's problem is to assure that revenues from the project, in this case a wind turbine power-plant, will be sufficient to repay the loan. To provide assurance that project performance requirements are met, lenders typically include extensive restrictions, called loan covenants, in their agreements with borrowers. The analysis presented in this paper includes the most important of these project finance loan covenants, namely debt service coverage requirements. To reduce the risk associated with project default, lenders usually require that a project or corporation maintain a minimum ratio of available cash to total yearly debt service (Kahn, 1995). The credit constraint is typically expressed as a minimum acceptable value for the debt service coverage ratio (DSCR). Because debt is frequently less costly than equity, iv there is a tendency for developers to maximize debt leverage. This tendency is limited by debt service coverage requirements. If a

project's DSCR is expected to be below the minimum DSCR required by a lender, the lender would require more equity up-front from the sponsor, which would reduce the project's debt fraction.

U.S. IOUs depend primarily on corporate financing, which relies on the attractiveness of a firm's balance sheet and prospective cash flows. When IOUs borrow money from public markets, their credit is based on the income stream of their entire asset base (generation, transmission, and distribution), not on an individual project. Corporate financing therefore lacks the degree of asset-specificity found in project finance. Unlike project finance investors, corporate issues of publicly sold bonds typically contain few restrictive covenants. The primary covenant is one that restricts the issuing of debt beyond certain limits (Smith and Warner, 1979). Additional debt can hurt bondholders because it reduces the ability of a firm to pay interest on existing debt. This capital structure constraint provides an implicit DSCR requirement, but DSCRs are not directly regulated on a project-specific basis.

Public entities can and have used both internal and project financing for power-plant development; this paper evaluates both alternatives. Internal or "corporate" financing has been the most common. As in IOU corporate financing, when a public utility in the U.S. borrows money from public markets, their credit is based on the income stream of their entire asset base, not on an individual project. The total income stream is therefore diversified by the inclusion of many assets. Financing for individual projects comes from internal funds and the issuance of additional tax-exempt bonds by the utility. Although these bonds typically have DSCR requirements, these requirements are company-wide, not project-specific.

To reduce "corporate" liabilities and risks, U.S. public utilities have also used project financing in recent power-plant development. In this scenario, the public utility creates a subsidiary to own and finance a power project and arranges to purchase power from the project through a power purchase contract. The subsidiary will typically use 100% tax-exempt debt financing, and security for the bonds comes only from the revenue stream of the project. Debt service coverage requirements (imposed on the subsidiary) are similar to those in private ownership, project financing arrangements. Project financing is typically more costly than internal financing for public utilities because security for the debt is based on the revenue stream of an individual project. From the public utility's standpoint, however, the risk reduction benefits of stand-alone, project financing, often exceed its costs (Olmsted, 1995).

Assumed Tax and Finance Differences

Table 2 lists key financing and tax differences among the three general ownership and financing scenarios modeled in this paper. See Wiser and Kahn (1996) for a more detailed description of these variables. Although the exact values of these variables depend on project-specific and macroeconomic factors, the estimates provided here are quite representative of those currently used in the cost-estimation techniques employed by utilities and private developers. The values for these parameters are consistent with those given in other sources, including Amitz (1995), Hart (1995), Hoffman (1995), Electric Power Research Institute (1993), Karas (1994), Sims (1995), Wolff (1995), and Wong (1995).

From the project developer's perspective, private ownership with project financing has some benefits compared to IOU ownership with corporate financing. First, project financing is generally non-recourse (sometimes limited recourse) to the parent company and therefore does not have a substantial impact on its balance sheet or creditworthiness. Second, the capital structure (the mix of debt and equity) of a project financed asset is frequently flexible, and can be optimized to minimize overall project costs. Because debt funds are frequently less costly than equity, private power-plant developers often maximize debt leverage, reducing overall financing costs. Jechoutek and Lamech (1995) and Nevitt (1983) discuss some negative aspects of project financing, including the large transaction costs associated with arranging the various contracts, high legal fees, higher debt and equity costs, and a greater array of restrictive loan covenants.

There is extensive literature on the question of capital structure and the relative costs of IOU corporate financing and NUG project financing (Perl and Luftig, 1990; Naill and Dudley, 1992; National Independent Energy Producers, 1991). Debt and equity investors in IOUs typically require lower returns than investors in individual power projects because of the asset diversity of corporate financing, the increased liquidity and information flow associated with public markets, the franchise monopoly provided to IOUs, and the implicit social contract with regulatory agencies to maintain the existence of utilities. Therefore, the lifecycle cost of IOU owned windplants is typically estimated using lower debt and equity costs, longer debt amortization, and no project-specific DSCR requirements.

Unlike NUGs using project financing, however, IOUs typically maintain a conservative capital structure and do not optimize project-specific debt-equity ratios. The most important cost of IOU ownership and finance is a less flexible capital structure, which typically results in a greater fraction of equity than in project financed power-plants. IOU income taxes are also estimated differently than NUG income taxes; for federal income tax purposes, IOUs receive a slightly less generous accelerated depreciation schedule, and, unlike NUGs, IOUs use tax normalization to calculate yearly income tax expenses.

Public utilities can obtain more favorable financing terms than private power producers because of the asset diversity associated with some forms of public finance, the franchise monopoly provided to public utilities, the quasi-monopoly ratemaking authority of public utilities, and the tax-exempt nature of public utility debt. As noted in Table 2, the specific benefits associated with public ownership include cheaper debt, longer debt amortization periods, greater use of low-cost debt in the capital structure, no income taxes, and reduced property taxes. Two primary costs are associated with public ownership and finance. First, because income taxes are not paid, public utilities cannot receive some of the tax advantages afforded to private owners of windpower facilities, namely accelerated depreciation and the federal 1.5¢/kWh production tax credit. Second, although public entities can obtain an equivalent cash production incentive in lieu of the PTC, the yearly funding for this renewable energy production incentive is highly uncertain.

BASE-CASE ANALYSIS RESULTS

Base-case cost results are provided in Table 3. These represent the apparent cost of windpower supply under the three basic ownership and financing scenarios, using the input cost, tax, operating, and finance assumptions described earlier. All results are presented as 20-year nominal levelized costs in 1997 dollars. Because capital structure, specifically the debt-equity ratio, in the private ownership, project financing structure is assumed to be variable, it is optimized to minimize the levelized cost of energy. Therefore, the private ownership results list not only the levelized cost of energy, but also the capital structure required to obtain this minimum cost.

Because of the uncertainly associated with funding for the REPI payments, they cannot be used as security for debt repayment and are often not even included in the assessment of the overall cost of wind facilities. For example, neither SMUD nor the Conservation and Renewable Energy Systems (CARES), both prospective public owners of U.S. windplants, relied on the REPI payments in project cost estimation (Wolff, 1995; Olmsted, 1995). The cost of public ownership is therefore estimated under two scenarios. The first assumes full expectation of receiving the 10-year, 1.5ϕ /kWh federal renewable energy production incentive. The second assumes that the REPI is not included in project cost-assessment.

-- INSERT TABLE 3 --

Although the absolute value of these levelized cost estimates depend on

many input assumptions, they are generally consistent with contract prices and estimated windpower costs for recent and planned U.S. windplants. For example, the contract prices for the following privately owned U.S. facilities are near the 5.0¢/kWh cost estimated for the NUG ownership scenario: (1) Kenetech/Lower Colorado River Authority (Bullock, 1995): (2) New World Power/Texas Utilities; (3) Kenetech/Northern States Power (Halet, 1995); and, (4) Kenetech/New England Power/Central Maine Power (Comnes, Belden, and Kahn, 1995). The public ownership cost estimates are also generally consistent with analysis performed by SMUD and CARES for their publicly owned wind projects. CARES estimates that its project (without REPI payments) will cost approximately 3.9¢/kWh on a levelized cost basis (CARES, 1995). SMUD has calculated a levelized life-cycle cost of 4.3¢/kWh without the REPI payment, and 3.4¢/kWh with the REPI (SMUD, 1995). Table 3 indicates that the use of traditional cost-assessment techniques results in substantial apparent cost savings for U.S. IOU and public utility ownership compared to private ownership with project financing. Under IOU ownership with corporate financing, the nominal levelized windpower cost is calculated to be 3.5ϕ /kWh, approximately 1.5ϕ /kWh less than in the private ownership, project finance scenario.

Assuming the 10-year REPI payments are included in the cost analysis, the public ownership, internal financing scenario is estimated to be the lowest-cost method to develop windpower projects (2¢/kWh less than private NUG ownership). Clearly, low-cost debt financing, tax exemptions, and the lack of project-specific DSCR requirements lower estimated project costs substantially. Even without REPI payments, this ownership and financing arrangement costs 0.6¢/kWh (12%) less than

a privately owned, project financed windplant. However, in this "no-REPI payment" scenario, IOU ownership is the lowest cost alternative.

Debt costs are more substantial in the public ownership, project financing scenario. If REPI payments are included, this scenario still costs much less than contracting with a private entity to supply windpower. In this case, the nominal levelized cost is approximately equivalent to that for the IOU ownership scenario and is 30% cheaper than for a privately owned, project financed facility. If REPI payments are not included in the cash-flow model, the apparent costs of a project financed, publicly owned windplant are approximately the same as the costs expected if the utility contracts for electricity from a private windpower supplier using project finance.

If the federal REPI and PTC subsidies are omitted altogether from the analysis, public ownership is by far the cheapest alternative. Private windpower ownership without the PTC is estimated to cost approximately 6.6ϕ /kWh. IOU ownership without the PTC is estimated to cost 5.9ϕ /kWh. As shown in Table 3, public ownership scenarios with internal and project financing are estimated to cost 4.4ϕ /kWh and 4.9ϕ /kWh respectively.

These results suggest that the most common form of windplant ownership and finance, namely private ownership with project financing, is also the most costly. The results validate the claim that apparent windpower costs can be reduced through direct utility ownership rather than contracting with NUG windpower suppliers. It is important to note, however, that these estimated savings may not represent *real* economies but may rather be a result of suboptimal analysis techniques and risk-shifting, issues that are discussed later.

SENSITIVITY ANALYSIS OF DRIVING FORCES

To determine the relative influence of the various financing and tax input differences among ownership scenarios, this section estimates the impact of variations in these inputs on the privately owned and project financed windplant.

The analysis suggests that the primary benefits associated with public ownership and finance of U.S. windplants come from the increased fraction of debt in the capital structure, reduced debt costs, a longer debt amortization period, and the lack of project-specific DSCR requirements. The estimated cost savings associated with IOU ownership and finance come primarily from debt and equity cost reductions, longer debt amortization, and the lack of project-specific minimum DSCR requirements.

Capital Structure

Capital structure refers to the mix of debt and equity in a power project.

Capital structure differs markedly among the three basic types of power project ownership. Debt is generally less costly than equity, so it would seem that the public power 100% debt capital structure has significant advantages over the other ownership arrangements. Because no project-specific DSCR requirements exist from the utility's perspective in the public ownership scenario, increased debt reduces project costs. In general, however, optimal capital structure also depends on the relative costs of debt and equity, and on the magnitude of the DSCR constraint.

The requirement to meet minimum DSCRs in the private ownership case creates the

need for higher-cost equity capital (and a resulting reduction in debt payments). Ignoring the effects of capital structure on debt interest rates and the minimum ROE, Figure 1 plots the nominal levelized energy cost for the privately owned windpower facility versus capital structure. As can be seen, the levelized cost of energy is minimized at a capital structure of approximately 50% debt and 50% equity. With greater debt, the power purchase price must increase to meet the DSCR constraint. With greater equity, the levelized cost increases because the minimum return on equity is higher than debt interest rates.

-- INSERT FIGURE 1 --

In response to the high debt leveraging seen in the U.S. independent power market, many analysts have claimed that NUGs have a financing advantage over utilities, which generally maintain a conservative capital structure with a greater proportion of high-cost equity capital (see, for example, Raboy, 1991). Kahn *et al.* (1992) respond to these claims by suggesting that the financing benefits associated with debt leverage are generally offset by the higher cost of debt and equity capital in the NUG project finance market. Interestingly, the results presented here suggest that, given current tax laws and windpower incentives, the optimal capital structure for a U.S. NUG windpower facility is approximately 50% equity and 50% debt. The capital structure of recent U.S. windplants is consistent with this analysis (Wong, 1995). A 50% debt fraction is similar to that maintained by most IOUs, but is in contrast to the 80% debt typical of U.S. gas-fired NUG projects. As described in Kahn (1995), the difference between the optimal windplant capital structure and the

debt-equity ratio of most gas-fired NUG facilities is almost solely due to the interactive effects of the windpower production tax credit and the need to meet stringent minimum DSCR requirements. These effects limit the benefits associated with the capital structure flexibility of privately developed and owned windpower plants.

Debt Interest Rate

Debt interest rates have a moderate impact on the levelized cost of windpower. To the extent that investor-owned and public utilities maintain lower debt interest rates than NUGs for project cost calculations, they have an apparent financial cost advantage. Figure 2 portrays the effects of debt interest rate on the minimum levelized cost of energy from a privately developed and project financed wind facility, and the optimal capital structure (% equity) needed to obtain this minimum cost. Holding all else constant, a reduction in the debt interest rate to that typical of recent public utility bond offerings (5.5%) decreases the cost of privately owned windpower by approximately 0.5¢/kWh. A reduction in interest rates to that used in IOU cost calculations decreases costs by a more modest 0.3¢/kWh. As debt costs increase, debt ratios generally decrease only slightly, and optimal capital structure is relatively insensitive to interest rate fluctuations.

-- INSERT FIGURE 2 --

Debt Maturity

Debt maturity has a considerable effect on the levelized cost of windpower. Figure 3 illustrates the impact of the debt amortization period on the levelized cost of energy and optimal capital structure for a privately owned facility, ignoring the term structure of interest rates. Levelized costs are highly dependent on debt term, ranging from a high of 6.3¢/kWh for 5-year debt to a low of 4.5¢/kWh for 20-year debt amortization. Holding all else constant, an increase in the amortization period from that typical of project financed private facilities (12 years) to that typical of investor-owned and public utilities (at least 20 years) decreases costs by approximately 0.5¢/kWh. Optimal capital structure is somewhat more variable in this case. For shorter amortization periods, the optimal structure becomes biased toward equity capital because the minimum DSCR constraint becomes more binding as yearly debt payments increase.

-- INSERT FIGURE 3 -

The impact of debt amortization on project costs was witnessed in the U.K. under the renewables portion of the Non-Fossil Fuel Obligation (NFFO), an auctioned set-aside program for renewables. Mitchell (1995), Elliot (1992), and Jackson (1992) describe the shortcomings of the first two competitive auctions of the NFFO, which set a contract end date of 1998 for winning renewables bidders. With a contract cut-off of 1998, the maximum fixed-price power-purchase contract length in the first two auctions was 7 years. This led to shortened debt maturity, as well as

larger equity risk premiums, and by most accounts substantially increased the cost of energy in the NFFO's first two competitive auctions.

Debt Service Coverage Ratios

Project-specific minimum DSCR requirements decrease the amount of debt leverage in the optimal capital structure and therefore increase levelized cost. In the private ownership, project finance case, this paper assumes that the contract price is constant in nominal dollars, front-loading the revenue stream and mitigating what is usually a *first-year* DSCR constraint. Regardless, the *overall* requirement still has substantial impact on capital structure and levelized costs. Figure 4 illustrates these effects. Holding all else constant, but lowering the private ownership minimum DSCR requirement to 1.0 (from 1.4), decreases levelized costs by approximately 0.5¢/kWh. As expected, debt leverage increases as the minimum required DSCR decreases.

-- INSERT FIGURE 4--

Equity Cost

Of the financial factors considered in this analysis, minimum returns on equity (ROE) have the greatest effect on the cost of privately owned windpower facilities with project financing. U.S. investor-owned utility corporate equity costs are substantially lower than those assumed for privately owned windplants (12%)

versus 18%), and public utilities do not have equity in the traditional sense. Figure 5 shows the impacts of the ROE on the minimum levelized cost of energy from a privately developed, project financed wind facility, and the optimal capital structure needed to secure this minimum cost. If the minimum ROE is reduced to that typical of IOUs, the estimated cost of privately owned windpower decreases by $0.9 \phi/kWh$. Capital structure is also relatively sensitive to changes in the minimum ROE. As expected, lower equity costs result in an increase of the equity fraction in the optimal capital structure.

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Property Tax Reductions

Public ownership results in reduced property tax payments although this benefit of utility windpower ownership is not as great as the financing advantages identified above. Under private NUG ownership, a decrease in property tax payments to those assessed in the public ownership case reduces the levelized nominal windpower cost to 4.8¢/kWh, a 3% decrease in cost from the base-case scenario.

Income Tax Exemptions and Depreciation Schedules

Income taxes are assessed differently in all three basic ownership structures.

Public utilities in the U.S. do not pay income taxes, IOU taxes are normalized and 7-

year acceleration depreciation is used, and NUG taxes are calculated using a 5-year accelerated depreciation schedule. The slight difference between NUG and IOU depreciation schedules has little impact on the levelized cost of windpower (Wiser and Kahn, 1996). For a more detailed description of tax normalization and its effects on windpower costs, see Hadley, Hill, and Perlack (1993).

To evaluate the value of the income tax exemption to public owners of windplants, the levelized cost of the privately owned wind facility with project financing is calculated assuming that income taxes are not paid. In order to evaluate only the tax exemption, the PTC income tax benefits are assumed to be still usable by the facility owner. This analysis suggests that an income tax exemption actually raises windpower costs to 5.6¢/kWh, a 12% increase in levelized costs from the base-case private ownership scenario. The income tax exemption is therefore a moderate disadvantage to public utility ownership of windpower facilities. The advantageous 5-year accelerated depreciation schedule allowed for private windplant owners drives these results by providing income tax benefits (even without the PTC) in the early years of project operation. An income tax exemption increases windpower costs because it does not allow the project owner to benefit from this advantageous depreciation schedule. This result is *not* reflective of public income tax exemptions in general, and other types of power installations (without such beneficial depreciation schedules) would not exhibit this effect.

DISCUSSION AND POLICY IMPLICATIONS

Ownership Tradeoffs

This paper has so far emphasized the cost savings associated with utility ownership and financing of renewable energy projects, but direct utility ownership has a number of other secondary benefits compared to contracting with NUG windpower suppliers using project finance. First, many utilities feel that only through direct ownership will they gain experience and a full understanding of the wind-turbine technology. Second, renewable power is generally viewed favorably by the public, and utility renewables ownership can enhance a utility's public image. Finally, U.S. investor-owned utilities can rate-base the capital expenditure of a project and earn a return on their investment; power purchase costs, on the other hand, are typically passed through to ratepayers directly, and shareholder returns are not allowed.

There are also costs to utility ownership of wind facilities. Principally, utilities and ratepayers face greater risk than with windpower purchases from NUGs. Dunkerley (1995) describes the project finance process as one in which an explicit recognition and pricing of project-related risks occurs. With utility ownership, on the other hand, many risks are implicitly passed on to and borne by the ratepayers. If these risks are not included in a utility's analysis of different ownership arrangements, the analysis will not be complete. Duvall and Vachon (1994) identify a number of risks related to windpower projects. These include: (1) installed cost and schedule risk; (2) wind resource and energy production risk; (3) wind turbine

technology risk; (4) operation and maintenance risk; and, (5) environmental risks.

The risk of project failure or under performance lies, in part, with the utility in utility ownership arrangements. In a power purchase agreement, performance risk largely remains with the developer because utility payments are typically fixed on a per-kWh supplied basis. Contract terms can be developed to minimize utility risk in direct ownership structures. For example, at a cost, turn-key construction contracts, performance guarantees, and fixed-price O&M contracts can all mitigate project risks for the utility owner. These strategies have been used in recent and planned utility wind ownership agreements (Duvall and Vachon, 1994; Olmsted, 1995). If the costs associated with these contract terms were included in the previous analysis, they would reduce the cost advantages of utility ownership, perhaps by as much as 0.5¢/kWh (Hoffman, 1995). Despite the risk reduction potential of these mechanisms, however, it is unlikely that contract terms can be developed to entirely eliminate all risks associated with direct project ownership. A quantitative comparison of the risks and rewards of utility ownership is beyond the scope of this paper; however, utilities typically exhibit more risk aversion than unregulated firms. The National Regulatory Research Institute (1994) lists a number of factors in utility regulatory structure that do not favor risk taking and innovation, and Jackson (1992) describes the institutional reluctance of utilities to invest in innovative new technologies. Olmsted (1995), Afranji (1995), and Duvall (1995) all indicate that a primary factor for SMUD, Portland General Electric (PGE), and PacifiCorp in contract negotiations with wind developers was to reduce utility risk.

Real versus Perceived Cost Savings

Using traditional U.S. utility and NUG cost-evaluation techniques, a levelized cost savings of approximately 15-40% (0.5-2.0¢/kWh) is estimated to result from utility ownership and finance as opposed to purchasing windpower from NUG suppliers through PPAs. However, it is important to determine whether utility ownership and financing of wind turbine power-plants is really cheaper than power purchases from entities using project financing or, instead, if utility cost analysis and implicit subsidies conceal the true costs and risks of utility windplant ownership.

Two aspects of this issue are discussed here: (1) the extent to which IOU ownership provides real cost savings to *ratepayers*; and, (2) the extent to which public utility ownership provides cost savings to the *nation* as a whole.

Both IOU revenue-requirement analysis and public utility internal finance cost analysis typically use corporate-wide bond and equity costs and terms to determine project costs. As discussed in more depth by Awerbuch *et al.* (1996), this approach ignores the variance in financial risks and therefore the *marginal* debt and equity costs and terms associated with different types of power facilities. Inclusion of a risky asset on a utility's balance sheet will marginally raise the cost of capital for the utility as a whole, a factor not explicitly considered quantitatively in most utility project assessments. The use of corporate average debt and equity costs in project evaluation therefore conceals the real cost of capital for projects whose marginal debt and equity costs are not the same as the corporate average. Because of resource and technology risks, privately owned windpower facilities typically have higher costs of capital (debt and equity) than similarly owned gas- and coal-fired

facilities (Kahn, 1995). The resource and technology risks apparent in the cost of capital for project financed windplants are not entirely eliminated by utility ownership. Therefore, the apparent cost savings of utility ownership, as identified in the previous analysis, may be overestimated because of the use of corporate average rather than marginal debt and equity costs and terms. Because public utilities obtain financing *and* tax advantages, public ownership of wind facilities, in contrast to contracting with an independent wind supplier, clearly provides real cost savings to public utility ratepayers. The real ratepayer savings from IOU ownership are slightly more dubious.

If an IOU has a lower *marginal* cost of capital for a windpower facility than does a private windplant owner, real cost savings can be achieved through utility ownership. As discussed in general terms by Brealey and Myers (1991) with reference to the capital asset pricing model, the extent to which these savings can be achieved depends on the ability of utility ownership to diversify the unique financial risks of windpower away in ways not available to capital markets and NUGs. This diversification would decrease real financing costs by reducing the utility's marginal cost of capital below that available to private windplant owners. An assessment of the magnitude of these real financing benefits is beyond the scope of this paper. However, a number of possible financial benefits of utility ownership can be identified. First, the increased liquidity of publicly traded securities compared to the privately-placed capital typical of NUGs should give IOU and public windplant owners a real financing advantage. Increased liquidity typically results in a deeper and more competitive pool of capital, and therefore lower financing costs (Bodington, 1993). Second, regulation, and the stability it brings, may also provide

real financing advantages to utility ownership. However, as utility restructuring changes traditional regulatory structures, these benefits will likely diminish. Finally, compared to the high transaction-specific costs of privately placed securities in project financing, especially for less-capitalized companies, utilities may have lower financial transactions costs (Nevitt, 1983). Therefore, although the actual savings associated with utility ownership may be overestimated in the previous analysis, some real savings should be available from this form of ownership. In any case, it is clear that traditional IOU revenue-requirement cost-estimation is imperfect in that it ignores risk differences among competing investment choices. As electric industry restructuring proceeds in the U.S., IOU analysis procedures may begin to account more rigorously for these different risks through the use of risk-adjusted discount rates (Awerbuch *et al.*, 1996).

A second, broad question, is the extent to which public ownership of windplants provides cost savings to the nation as a whole. Much of the benefit of public ownership comes from the tax-exempt nature of public bonds and the property tax reductions available to public entities. Although these factors may mean that ratepayers save when public utilities own windpower facilities instead of purchasing power from independent windpower suppliers, the entirety of these savings are not being provided to the nation as a whole. Public utility projects are subsidized by federal and state governments through income tax exemptions and allowance for tax-exempt bonds, and by state and local governments through property tax reductions. The tax revenues that are not collected from activities associated with public utilities must be obtained through other tax mechanisms. To the extent that these replacement taxes are spread over more than just the public utility ratepayers, public

utility ownership is cross-subsidized. Therefore, although public ownership of windplants is less costly for the utility and its ratepayers than purchases from a private windpower provider, the cost reduction is partially subsidized by other segments of the economy.

Electric Industry Restructuring

Electric industry restructuring and deregulation could significantly affect windpower development and the finance results presented in this paper. Electric utility restructuring is likely to fundamentally change the financing of power projects in general, and windpower projects in particular. The ultimate effects will depend on the structure and organization of the restructured market as well as the potential adoption of public policies to promote renewables. If merchant plant financing and shorter power purchase contracts become the norm as many people anticipate, a greater infusion of equity capital and shorter debt terms might be expected. In comparison to the traditional power generation alternatives, and assuming no new renewable energy promotion mechanisms are developed, renewable energy projects are likely to be negatively affected by these changes. The technology and resource risks associated with windpower and other types of renewables, and the high installed cost of renewable energy facilities (in contrast to gas), make windpower and other renewables particularly vulnerable to increased financing costs and restrictions.

Industry restructuring has slowed the pace of domestic wind development substantially, and a number of U.S. utilities have abandoned or are attempting to

renegotiate past commitments to own or purchase renewable power technologies. If the emphasis on short-term costs continues, cost reductions and/or renewables support policies will become even more important in helping wind compete with low-cost, gas-turbine power-plants. Reductions in the cost of financing may therefore become even more essential if the technology hopes to compete in a restructured industry. Although the industry is moving away from regulated utility investment in new generation sources, the pace and outcome of industry restructuring will vary by state and country, and the transition will not be seamless. Utility ownership of windpower facilities to reduce costs is likely to remain a possible mechanism for windpower development in many areas of the country. It is important to note, however, that to the extent that industry restructuring results in improved utility cost-analysis techniques (i.e., techniques that more appropriately compare investment options with different risk profiles), utility project assessment procedures may no longer over-estimate the potential savings from direct ownership of renewables projects.

If the private power and project financing model continues to dominate the wind industry, and restructuring leads to increased market risk, additional policies promoting renewables may be required to sustain the U.S. wind and renewables industries. For example, if long-term power sales contracts become scarce, there will be a need for policies that either: (1) preferentially supply long-term contracts (e.g. auctioned contracts) to renewable energy developers; (2) provide sufficient financial incentives to renewables developers that long-term power contracts are unnecessary (e.g. with production incentives, tax incentives, etc.); or, (3) provide lender-support (through loan guarantees, for example) so that long-term contracts are

less essential.

CONCLUSION

This paper has analyzed the impacts of financing and ownership arrangements on the apparent cost of utility-scale renewable energy facilities. The cost of renewable energy in general, and windpower in particular, is highly sensitive to financing variables. This analysis suggests that levelized windpower costs can vary by up to 40% as a result of simple changes in ownership and financing structure.

Using traditional economic and financial analysis techniques, utility ownership of U.S. windpower facilities is shown to lead to a significantly lower estimated levelized cost of energy. These results help explain why some utilities have growing interest in directly investing in renewable energy facilities rather than purchasing power from private renewable energy developers through power purchase agreements. It is also clear that the estimated cost savings of utility ownership are at least partially offset by the increased risk absorbed by utility shareholders and ratepayers in utility-ownership scenarios. Therefore, although utility and ratepayer cost savings may be available through some forms of utility renewable energy project ownership, utilities should use traditional cost-estimation techniques with caution.

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ENDNOTES

i. Surveys by the American Wind Energy Association (1995) and Renewable Northwest (1995) (updated by the author) indicate that of the approximate 370 MW of wind projects currently in the latter stages of development in the U.S., 180 MW are utility-owned facilities. Of the utility-owned capacity, half is expected to be owned by public utilities and half by IOUs.

- ii. See Wiser and Kahn (1996) for a more detailed description of the models.
- iii. In general, the levelized cost of energy is relatively insensitive to changes in the project assessment period. Extending the assessment period from 20 to 30 years, for example, decreases project costs by $0.2\text{-}0.3~\phi/\text{kWh}$ on a nominal levelized basis for all three ownership scenarios analyzed in this paper.
- iv. There is an extensive literature on optimal capital structure and the relative merits of debt and equity financing. Brealey and Myers (1991) conclude that optimal capital structure depends on a number of variables, including taxes, risk aversion, asset type, and the desire for financial slack. Empirical evidence in the private power market suggests that project developers typically attempt to maximize debt in the capital structure because it is widely considered less costly than equity (Kahn *et al.*, 1992).
- v. IOUs are likely to depreciate windpower equipment based on a 7-year modified accelerated cost recovery system (MACRS) rather than the 5-year schedule used by NUG windpower owners.
- vi. Unlike private power and IOU projects, public entities typically expect to pay property taxes only on the unimproved value of the land, not on the increased value of the windpower facility (Olmsted, 1995; Wolff, 1995).
- vii. Although not assessed quantitatively, financial risk may be an important qualitative factor in utility decisions regarding windplant investments.
- viii. The enhanced and diversified credit support associated with corporate finance may reduce direct utility financing costs compared to asset-specific project financing. However, these reduced costs are at least partially offset by the increase in corporate and balance-sheet risk associated with this form of financing.
- ix. For example, the 144A debt market (a rated and more liquid form of unregistered debt) provides additional liquidity and a deeper capital pool than the pure private-placement market typical of NUGs. Wong (1995) estimates that using this mechanism might shave up to 100 basis points from the debt interest rate of a non-utility power-plant.